STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2004-248

April 11, 2005

MAINE PUBLIC UTILITIES COMMISSION
Inquiry into the Status of the Reliability and
Security of the Electric Grid

COMMENTS OF BANGOR
HYDRO-ELECTRIC COMPANY

Bangor Hydro Electric Company's
Response to the Maine Public Utility Commission's Draft Report of the Reliability and Security of the Grid in Maine

In 2002 management at Bangor Hydro Electric-Company adopted a new Mission Statement which is…"To be the Best Electric Delivery Company in the Northeast". One of the first steps taken to realize this goal was the implementation of a new asset management model. In simple terms, this approach requires that the Company measure the performance of its system to determine where it is weak. Next, work is performed to improve reliability (as needed) and after which measurements are made to ensure that targeted actions had the desired effect. The Company is pleased with the progress it has made since the implementation of this new asset management process. However, it realizes that it is still short of its goal and that more work is needed to ensure that the right programs are in place to maintain reliability at prudent and acceptable cost levels.

The Company is pleased that the Commission recognized its hard work and new ways of doing business in its Draft Report. The Company remains committed to providing better service for all its customers and has recently implemented a new comprehensive asset inspection program for its entire transmission and distribution plant for this reason. After reviewing the Draft Report the Company prepared comments on its contents and respectfully submits the following responses for the sake of clarifying the Company's position on various items or to correct minor errors.

Re: Transmission Study Time Period

The Company would like to clarify that its recently completed transmission planning study examined base case and contingency power flow needs for a 10-year horizon instead of 20 as stated on page 45 of the Draft Report.

Re: Transmission Project Update

On pages 46 and 47 of the Commission's Draft Report a discussion of the Company's current transmission projects and their benefits to customers was highlighted. The Company would like to take this opportunity to update the Commission on progress made regarding these long-range transmission projects. Specifically, The Company believes that it is important to note the priority of the Hancock County Reliability Project in the Company's transmission planning horizon. The Company agrees with the Commission's assessment that the transmission infrastructure serving Washington County, in particular Line 66, may not meet the reliability expectations of today's customers. This fifty-year-old line suffers from increased exposure to outage due to its sheer length (over sixty miles) and, when interruptions due occur restoration can be slowed due to limited accessibility. This existing line does, however, have the capability to serve the forecasted load in the area for the next several years. The most recently completed transmission planning study shows higher priority concerns in the Company's Hancock division. The ability to support voltage and load growth on Mount Desert Island and the ability to serve load in Ellsworth and on the Island under certain contingencies has elevated projects to mitigate these system weaknesses to a higher level. It should also be understood that the Company's plans for further transmission enhancements in both Hancock and Washington County have begun and from beginning to end fall into a five year horizon.

The Company wishes to clarify that the costs of the transmission project in Washington County from Ellsworth to Harrington mentioned in the Commission's report on page 46 is very preliminary. Detailed estimates of permitting costs, ROW acquisition costs, along with line and substation construction costs have not been completed to date.

Re: 50 Megawatt Single Contingency Loss Criteria

On page 45 of the Commission's report and pages 6 and 18 of the Liberty Consulting Group's Report (Attachment A) a concern was raised that the Company's 50MW single contingency load loss criterion appeared excessive.

The transmission planning criteria, particularly loss of load criteria, are used by the Company to trigger or identify areas of concern or system weakness during transmission planning studies. Alternatives used to mitigate against these system weakness need to be balanced with customer expectations for reliability, regulator expectations for reliability, industry standards, and certainly costs. The Company agrees that its loss of load criteria should be reviewed from time to time and will commit to the Commission's request of providing a cost/benefit analysis of changing its criteria to a higher standard as part of its ARP 2006 Annual Reliability Report.

Re: Transmission Studies Conducted with Weather Normalized Load Forecasts

On page 15 of the Liberty Consulting Group's report it was written that the Company uses historical peak loads as base lines for transmission load forecasting. In fact, loads are not normalized for average weather conditions. Members of NEPOOL have adopted 50/50 and 90/10 load-forecasting methodologies, which the Company is in the process of investigating.

Re: Identification and Performance Improvement of Worst SAIFI and CAIDI Circuits

On page 53 of the Commission's Draft Report a disparity was highlighted between the Worst SAIFI and CAIDI lists reported by the Company in its Annual Reliability Improvement Reports and those contained in Appendix H of the Draft Report. The Company would like to clarify that the list appearing in its 2002 Annual Reliability Improvement Report is a summary of the top 15 circuits impacting the Company's overall SAIFI level for that year and not a list of circuits with the highest individual SAIFI. The Company did include a list of individual circuit SAIFI and CAIDI after the removal of excludable events in Appendix E but did not sort the list so those with poorer reliability or slower restoration times appeared at the top. In 2003, the Company changed its method of reporting and began listing the top 10 circuits with worst individual SAIFI and CAIDI after the removal of storm events within the body of its report. This approach was continued in its 2004 Annual Reliability Improvement Report.

The Company chose to list circuits in this manner for its 2003 and 2004 reports because it is consistent with the manner in which the Company's overall power system performance is measured through the ARP. It was believed that supplying the Commission with lists of this type would enable an apple-to-apple comparison of individual circuit reliability to system reliability after the removal of exclusions and would show (on a consistent basis) those with poorer reliability and others with slowed power restoration times.

In an effort to improve system SAIFI in 2002 the Company identified circuits that where disproportionately effecting overall SAIFI because of vegetation (weather and trim) and animal contact reasons. These circuits were inspected and trimmed accordingly. In 2003 and 2004, the Company continued this approach under the guidelines of its RRP effort. However, in 2004 it also began looking at how improvements (trimming or other) could be made to improve the reliability of the worst SAIFI circuits listed in its Annual Reliability Improvement Reports. With its recent change from reactionary to proactive circuit inspections, the Company recognizes that some circuits (for whatever reason) will still require examination and corrective action out-of-cycle for unexpected reasons. The Company decided to develop its list of worst SAIFI circuits for its current asset management program through the use of the IEEE 1366-2001 2.5 Beta exclusion methodology, for which acceptance by the electric utility industry is growing.

The Company elected to use circuit performance less the effects of major events because it believed that excludable events are caused by failures that in most instances can not be prevented by cost-effective construction and maintenance practices. The ice storm of 1998 is an excellent example of a major event that should be removed from reliability statistics before the identification of worst SAIFI or CAIDI circuits is made. On a lessor scale, the windstorm that occurred on November 13th, 2003, which had peak recorded wind gusts of 69 miles per hour, is another example of an abnormal event that warrants exclusion. The Company welcomes a discussion with the Commission on the method that it should use to identify circuits with worst SAIFI for the sake of follow-up corrective action.

Re: Reliability of Distribution Circuits serving Sparsely Populated Rural Areas

The Company agrees with the conclusion found on page 76 of the Draft Report that stated that any asset management program implemented by a utility to improve the reliability of its power system should not be done at the detriment of service to customers living in less populated areas.

Prior to 2002, there was no formalized or centralized reliability management effort in place at the Company. In mid-2002 its newly formed asset management group performed an extensive review of the reliability of its entire distribution system. The result showed that it was unlikely that the Company would realize ARP SAIFI and CAIDI targets by the end of the year unless significant improvement actions were undertaken. As a result, a Reliability Recovery Plan was formed to return and stabilize power system reliability indices to acceptable levels. Throughout the fourth quarter of 2002 and into 2003 expenditures were primarily justified based on large circuits and line sections with poor reliability which, when improved, would impact the largest amounts of BHE's customers. However, at the end of 2003, the Company developed its reliability improvement program to include an analysis and evaluation of its worst performing circuits independent of size or customer density. This was further refined at the end of 2004 and documented as part of the Company's Comprehensive Asset Management Program Plan (ref. BHE 02/17/05 filing as a response to Oral Data Request No. G2, Item 4).

This new proactive T&D Inspection Plan includes a yearly review of reliability data for the purpose of identifying the circuits for poor reliability after which, a causation analysis is performed to determine why these circuits were poor performers and whether or not corrective action should be taken. Poor performance is determined not only by worst SAIFI over the past 12 months, but also includes those circuits with continuous degradation over the past three years and circuits with greatest percent negative change in SAIFI for the recent year compared to the past year. The company feels that its T&D Inspection Plan includes not only provisions for a proactive, sustainable program, but also includes a reasonable approach for identifying worst performing circuits independent of customer density, for which corrective actions will be performed if deemed necessary after an analysis of outage data is completed.

Re: Transmission and Distribution Plan

On pages 58 and 59 of the Commission Draft Report and on pages 6, 16 and 18 of the Liberty Consulting Group Report the Company's current distribution and roadside inspection plan was characterized as reactionary and not performed on a periodic basis, but that a periodic inspection plan was being developed. The Company is pleased to report that the development of its new comprehensive asset management inspection program, which focuses on ensuring the long-term viability of its overhead distribution and transmission facilities (both in right-of-ways and roadside), was completed late last year and is fully implemented and underway. A detailed copy of this plan was submitted to the Maine Public Utilities Commission (MPUC) on February 17, 2005 in its response to Oral Data Request No. G2, Item 4.

This inspection program establishes proactive periodic cycle examinations of the Company's in-service distribution and transmission assets, of which highlights are listed as follows:

- Distribution circuits will be inspected once every six years.
- Distribution line segments serving more than 1000 customers will be designated as "special consideration" and inspected every three years.
- An unknown quantity of distribution and transmission lines will be inspected annually based upon poor performance. A pre-established procedure that takes into account a distribution or transmission circuit's percent change in SAIFI (this year compared to last), 3-year SAIFI trend and SAIFI standing for

the current review period was developed by Planners and will be used to identify assets that require further outage data analysis and field examination.

- Transmission lines located in right-of-ways (ROW) will be inspected once every five years. (Note: This activity is in addition to the Company's regular annual helicopter patrols and groundline inspection and treatment program of poles in right-of-ways).

- Transmission lines located alongside roads with a distribution circuit underneath will be inspected once every six years and at the same time as its adjacent distribution circuit is examined.

- Transmission lines located alongside roads without a distribution circuit underneath will be inspected once every six years and at the same time that the closest distribution circuit is examined.

- Transmission and distribution spans crossing highways, interstates and rivers will be inspected once every three years.

After training of Company Service Planners was completed, inspections of over 900 miles of distribution and transmission lines along with the examination of 33 water and road crossings began in early 2005. Currently, workers have inspected all transmission lines (both roadside and ROW) and critical line crossings called for in the plan. Additionally, roughly 75% of all required distribution circuit inspections were performed with others not yet done scheduled for completion by the end of April.

All facility and vegetation encroachment concerns observed during these inspections were recorded in the Company's Geographic Information System (GIS) along with a corresponding priority level for repair/trim work needed. T&D Planners are currently reviewing this data after which follow-up maintenance work requests will be generated to begin the repair process. Assets requiring immediate corrective action because are being addressed on a priority basis.

Upon the conclusion of all inspection work, follow-up meetings will be held with asset inspectors in an effort to identify what worked, what didn't work and how the process of inspecting assets in 2006 can be improved and streamlined.

Re: Frequency of Transmission Roadside Inspections

The suggestion was made on page 7 and 18 of the Liberty Consulting Group's Report (Draft Report Appendix A) "that the Company should either separate its roadside transmission plant from its distribution plant when conducting its reliability and other maintenance programs or otherwise ensure that roadside transmission receives the same level of inspection and maintenance as provided for in the transmission programs."

The Company agrees with this assessment and has decided to designate all roadside transmission plant as special consideration lines for which an inspection of each will be performed every three years instead of six, as was previously specified in the Company's comprehensive asset management inspection program. This additional work means that roughly 70 more miles of roadside transmission line will be examined annually.

Re: Frequency of Distribution Substation Inspections

Bangor Hydro would like to clarify the statement, "BHE inspects each of its distribution substations monthly", which can be found on page 56 of the Commission's Draft Report. The Company currently inspects each of its distribution substations on an every other month basis. Bangor Hydro performed monthly distribution substation inspections in years past, but a review of its maintenance practices and procedures in 2003 the Company determined it was prudent to lessen the inspection frequency for these sites. In addition, critical transmission substations are inspected on a weekly basis.

Re: Percentage of Miles Inspected under the Company's RRP

Bangor Hydro would like to supplement the following statement found on page 57 and 58 of the Commission's Draft Report.

> "Therefore, by the end of 2004 a total of 50 circuits, out of the company's 179 circuits, had been visually inspected by foot or vehicle patrols and all vegetation management abnormalities or imminent hazards due to plant or equipment condition were recorded as part of such inspections. "

The Company believes that it is important to give the reader a sense of what was accomplished through the inspection of these 50 circuits. Because the RRP targeted primarily larger more densely populated circuits, we are compelled to point out that while 50 circuits only represents 28% of the total, these particular circuits serve almost 60% of the customers taking electric delivery service from the Company and over 60% of the transmission and distribution circuit miles located throughout our service territory. As a result, while the RRP effort was targeted in scope, it was also far reaching and benefited many customers and involved a significant portion of the electrical grid the Company maintains.

Re: Periodic Testing of Distribution and Roadside Transmission Pole Plant

Both the Liberty Consulting Group and the Commission's report stated that none of the electric utilities in Maine have a structured periodic pole-testing program for its distribution plant. The NESC states that poles and crossarms should be replaced when their strength deteriorates to some predetermined percentage of their designed and installed capacity. The Company believes that the Commission's assessment may not be entirely accurate. The Company has recently implemented a new comprehensive asset inspection program where all poles and crossarms are visually inspected on a periodic basis. Poles of questionable condition found during these inspections are "sounded" to determine a level of internal decay. The Company's recent history of broken or failed poles is on the order of approximately 20 annually over the past two years, which is an extremely small percentage of the Company's 137 thousand poles. We expect this failure rate to decline over time due to the recent implementation of a new periodic inspection program. The Company also believes that the cost/benefits of implementing a ground line testing and/or treatment program should be well understood prior to its implementation. The Company believes that its current program is compliant with NESC and that ground line inspections provide only marginally improved data as to a pole's actual remaining strength. The Company also feels that mandatory implementation of a ground line program should be extended to other parties who share ownership of this equipment.

In summary, the Company believes its current programs meet the spirit of NESC, are in the customer's best interests, and are consistent with good utility practice. We certainly welcome the Commission's comments on our position as well as other utilities' comments in response to the Commission and Liberty's findings regarding this issue.

<u>Re: T&D Capital and O&M Spending Policies and Practices</u>

On page 14 of the Liberty Consulting Group's report it was stated that…""BHE's Policies and practices related to T&D capital and O&M spending are largely unwritten." The Company believes that this sentence does not characterize correctly the Company's O&M and Capital spending policies and practices. In particular, policies around maintenance spending related to transmission, distribution, and substations are very well documented in maintenance plans that are developed annually based on predetermined criteria. These programs are developed in accordance with industry standards, manufacturer's recommendations, applicable codes, and good utility practices. It is true that the Company's capital spending policies are largely unwritten, however approximately 50% of capital spending is non-discretionary (i.e., new services, MDOT roadwork, etc…). Remaining capital is spent to improve or expand the system to meet predicted growth based on 5-year distribution and 10-year transmission plans, to repair and maintain existing system deficiencies as determined by inspection and maintenance programs, and on projects that improve efficiencies within the business (such as automated meter reading).

<u>Re: Operating Voltage for Line 66</u>

On page 15 of the Liberty Consulting Group's report it was written that the voltage for the line serving eastern Maine (Line 66) is 69kV. This line in fact operates at a voltage of 115KV.

Respectfully submitted,

/s/ Gayle A. Morin
Paralegal